

Source and name of referenced material	49 CFR reference
(5) ASME/ANSI B31.8S–2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines.”	§§ 192.903(c); 192.907(b); 192.911 Introductory text; 192.911(i); 192.911(k); 192.911(l); 192.911(m); 192.913(a) Introductory text; 192.913(b)(1); 192.917(a) Introductory text; 192.917(b); 192.917(c); 192.917(e)(1); 192.917(e)(4); 192.921(a)(1); 192.923(b)(1); 192.923(b)(2); 192.923(b)(3); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(2); 192.925(b)(3); 192.925(b)(4); 192.927(b); 192.927(c)(1)(i); 192.929(b)(1); 192.929(b)(2); 192.933(a); 192.933(d)(1); 192.933(d)(1)(i); 192.935(a); 192.935(b)(1)(iv); 192.937(c)(1); 192.939(a)(1)(i); 192.939(a)(1)(ii); 192.939(a)(3); 192.945(a).
(6) 2007 ASME Boiler & Pressure Vessel Code, Section I, “Rules for Construction of Power Boilers 2007” (2007 edition, July 1, 2007).	§ 192.153(b).
(7) 2007 ASME Boiler & Pressure Vessel Code, Section VIII, Division 1, “Rules for Construction of Pressure Vessels 2” (2007 edition, July 1, 2007).	§§ 192.153(a); 192.153(b); 192.153(d); 192.165(b)(3).
(8) 2007 ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, “Alternative Rules, Rules for Construction of Pressure Vessels” (2007 edition, July 1, 2007).	§§ 192.153(b); 192.165(b)(3).
(9) 2007 ASME Boiler & Pressure Vessel Code, Section IX, “Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators” (2007 edition, July 1, 2007).	§§ 192.227(a); Item II, Appendix B to Part 192.
E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):	
(1) MSS SP–44–2006, Standard Practice, “Steel Pipeline Flanges” (2006 edition).	§ 192.147(a).
(2) [Reserved].	
F. National Fire Protection Association (NFPA):	
(1) NFPA 30 (2008 edition, August 15, 2007), “Flammable and Combustible Liquids Code” (2008 edition; approved August 15, 2007).	§ 192.735(b).
(2) NFPA 58 (2004), “Liquefied Petroleum Gas Code (LP-Gas Code).”	§§ 192.11(a); 192.11(b); 192.11(c).
(3) NFPA 59 (2004), “Utility LP-Gas Plant Code.”	§§ 192.11(a); 192.11(b); 192.11(c).
(4) NFPA 70 (2008), “National Electrical Code” (NEC 2008) (Approved August 15, 2007).	§§ 192.163(e); 192.189(c).
G. Plastics Pipe Institute, Inc. (PPI):	
(1) PPI TR–3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), “Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe” (May 2008).	§ 192.121.
H. NACE International (NACE):	
(1) NACE Standard SP0502–2008, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology” (reaffirmed March 20, 2008).	§§ 192.923(b)(1); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(1)(ii); 192.925(b)(2) Introductory text; 192.925(b)(3) Introductory text; 192.925(b)(3)(ii); 192.925(b)(3)(iv); 192.925(b)(4) Introductory text; 192.925(b)(4)(ii); 192.931(d); 192.935(b)(1)(iv); 192.939(a)(2).
I. Gas Technology Institute (GTI):	
(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology.”	§ 192.927(c)(2).

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.7, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at [www.fdsys.gov](http://www.fdsys.gov).

### § 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) An operator must use API RP 80 (incorporated by reference, see § 192.7),

to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not

## § 192.9

## 49 CFR Ch. I (10–1–11 Edition)

extend beyond the furthestmost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthestmost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of “production and preparation for transportation or delivery of hydrocarbon gas” within the meaning of “production operation.”

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is de-

termined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR §190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthestmost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of §192.9, “regulated onshore gathering line” means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A .....	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.	Class 2, 3, or 4 location (see § 192.5)	None.
B .....	—Non-metallic and the MAOP is more than 125 psig (862 kPa). —Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	Area 1. Class 3 or 4 location ..... Area 2. An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. .... (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings. (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

[Amdt. 192–102, 71 FR 13302, Mar. 15, 2006]

### § 192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the re-

quirements in §192.150 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §192.150 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing